



**Final Report**

**AB 117 Assessment Report  
for the City and County of  
San Francisco**



**San Francisco Local Agency Formation  
Commission**

**August 2003**



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**Via FedEx**

Ms. Gloria L. Young  
Executive Officer  
Local Agency Formation Commission  
1 Carlton B. Goodlett Place, Room 244  
San Francisco, California 94102-4689

**Subject: Final Report**

Dear Ms. Young:

Enclosed are 35 comb-bound original copies of R. W. Beck's AB 117 Assessment Report for the City and County of San Francisco. The report reflects comments received through the SF LAFCO public comment period (July 25, 2003) and comments received informally from the SFPUC through August 1, 2003.

Please do not hesitate to contact me if you have any questions.

Sincerely,

R. W. BECK, INC.

A handwritten signature in cursive script that reads 'Michael A. Bell'.

Michael A. Bell  
Principal and Senior Director of Client Services

:jm  
Encl.

c: Nancy Miller (Hyde, Miller, Owen & Trost)  
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# San Francisco Local Agency Formation Commission

## AB 117 ASSESSMENT REPORT FOR THE CITY AND COUNTY OF SAN FRANCISCO

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This report has been prepared for the use of the client for the specific purposes identified in the report. The conclusions, observations and recommendations contained herein attributed to R. W. Beck, Inc. (R. W. Beck) constitute the opinions of R. W. Beck. To the extent that statements, information and opinions provided by the client or others have been used in the preparation of this report, R. W. Beck has relied upon the same to be accurate, and for which no assurances are intended and no representations or warranties are made. R. W. Beck makes no certification and gives no assurances except as explicitly set forth in this report.

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## EXECUTIVE SUMMARY

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# EXECUTIVE SUMMARY

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## Background

The San Francisco Local Agency Formation Commission (SF LAFCO) engaged R. W. Beck, Inc. (R. W. Beck) on February 10, 2003, to provide an independent analysis in light of recently adopted state Community Choice Aggregation legislation Chapter 838 (AB 117–Migden) as it might apply to the City and County of San Francisco.

This Assessment report provides the following information for SF LAFCO's consideration and deliberation in determining whether or not to proceed with the submittal of a Community Aggregation Implementation Plan to the California Public Utilities Commission (CPUC):

- Overview of Community Aggregation
- Technical and legal analysis of AB 117
- Benefits and risks of Community Aggregation in San Francisco
- Factors that will determine the feasibility of Community Aggregation in San Francisco
- Preliminary assessment of the feasibility of Community Aggregation in San Francisco
- Conclusions and recommended next steps

The City and County of San Francisco is in a unique position to take advantage of the benefits of Community Aggregation as permitted under AB 117. San Francisco has positioned itself to take an active role in resolving energy issues that have negatively impacted the City in recent years. These issues include:

- The continued operation of the inefficient and environmentally unfriendly Hunter's Point and Potrero Power Plants.
- Insufficient transmission system planning and implementation.
- Attendant reliability problems resulting in frequent and costly service interruptions.
- Vulnerability to price fluctuations and high rates.
- Bankruptcy of the Pacific Gas and Electric Company (PG&E).

AB 117 provides a means by which the City and County of San Francisco can establish local control over the planning and implementation of its future energy supply. It also provides an opportunity to create a resource mix and establish pricing mechanisms that are uniquely tailored for San Francisco.

## Conclusions

Based on R. W. Beck's analysis of information provided by various sources, including the City and County of San Francisco; subdivisions of the City and County, such as the San Francisco Public Utilities Commission (SFPUC), Department of Environment, Hetch Hetchy Water and Power; the CPUC, California Energy Commission, California Power and Conservation Financing Authority, California Independent System Operator, PG&E, and other sources, we have reached the following general conclusions:

- Under conservative assumptions, annual estimated savings due to Community Aggregation in San Francisco are likely to be between \$10 and \$35 million annually (5-20%). Actual savings will be dependent on a number of critical factors, including:
  - whether the generating credit given by PG&E to Direct Access customers is approximately equal to that to be provided for Community Aggregation, as assumed in the analyses,
  - other non-bypassable charges that might imposed by the CPUC,
  - the outcome of the PG&E bankruptcy,
  - wholesale electricity market prices, and
  - natural gas prices.
- If San Francisco can integrate surplus Hetch Hetchy resources and the newly acquired Williams Companies combustion turbines into the power supply portfolio, savings will increase. Analyses will need to consider the loss of revenues to the City from any sales of these resources into the wholesale electricity markets.
- The San Francisco load profile should be less costly to serve than the PG&E system load profile. Preliminary analyses indicated a small cost advantage based on a combination of non-detailed load profile data and market price information that was not robust or was affected by dysfunctional electricity markets. More complete data from PG&E for the San Francisco service area, including current data by customer segment, will be required to confirm these results.
- The CPUC has been slow to address implementation plans and cost responsibilities for Community Aggregation. However, the City is in a good position to work with the CPUC to obtain consideration of its needs as CPUC rules are evaluated and adopted. If San Francisco is interested in pursuing Community Aggregation, it is important to be active in this process.
- Analysis of the advantages and disadvantages of the various potential governance structures cause us to recommend that the SFPUC is the most logical choice to lead further investigation into a Community Aggregation Plan.
- There are a number of factors that will undoubtedly change a final analysis of Community Aggregation, including the determination of non-bypassable charges by the CPUC; site-specific San Francisco load data that PG&E will be required to

provide; the outcome of the PG&E bankruptcy; and the ground rules for future pricing decisions either through a market or regulated return basis. In any case, it appears that the potential benefits of Community Aggregation warrant the SF LAFCo's consideration of the Community Aggregation and that the SFPUC would be the appropriate agency to undertake the tracking of CPUC rulemaking and related analyses.

- If the San Francisco Board of Supervisors ultimately elects to implement Community Aggregation and authorizes the preparation by the City and County of San Francisco of an Implementation Plan to be filed at the CPUC, we estimate that it would take approximately four to six months to complete the plan and another four to six months to receive CPUC authorization once the plan is filed. Therefore, it is unlikely that Community Aggregation could be implemented much before 2005. An outline of the steps needed to implement Community Aggregation is contained in Section 5, and considerable discussion of the work that would need to be done is included in all sections of this report.

R. W. Beck would like to thank the Executive Director of the SF LAFCo, Gloria Young; Nancy Miller of Hyde, Miller, Owen & Trost; and Ed Smeloff, Anne Selting, and all of the staff of the SFPUC that provided insight and comment for their contributions to this report.







## Section 1

# OVERVIEW OF COMMUNITY AGGREGATION

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## Section 1

# OVERVIEW OF COMMUNITY AGGREGATION

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### What is Community Aggregation?

Community Aggregation is the process by which a unit of local government replaces an existing Investor-Owned Utility (IOU) as the provider of power supply resources to its constituents. The power supply resources can be a physical resource, such as a power plant or renewable resource facility, or it can be provided through a third-party supplier that either owns or purchases power on the open market. Community Aggregation differs from municipalization in that the local government does not need to acquire or own either transmission or distribution facilities in order to provide the power supply resource. Community Aggregation has been facilitated by the recent deregulation of electrical generation facilities, by more active markets for buying and selling power supply, and by passage of Community Choice Aggregation legislation in California.

### Community Aggregation in Other States

The states other than California that have been active in the development and implementation of Community Aggregation have been Massachusetts and Ohio.

Massachusetts was the first state to provide for Community Aggregation as part of its 1997 electric restructuring law. The Massachusetts's program presently allows four different options.

- **Standard Offer Service** – Electric distribution companies provide power at a price established in advance through March 2005, at which point customers are switched to Default Service.
- **Default Service** – Electric distribution companies supply power at a variable price that moves with the market price of power.
- **Aggregator** – Customers have the option of taking power through local governments or other buying groups at prices provided for by the aggregator. This provides the avenue for local government agencies to provide electric supply services.
- **Competitive Power Supplier** – Customers have the option of purchasing from a number of licensed suppliers. Currently, there are 13 such licensed suppliers in Massachusetts.

The second state to implement Community Aggregation was Ohio. Its program was modeled after Massachusetts's and includes provisions for government aggregation on either an Opt-In or Opt-Out basis. In the case of the Opt-In alternative, customers can

choose to join the local aggregator. In the case of the opt-out alternative, all local customers are automatically switched to the government aggregator, unless they opt not to participate. If the customer selects to remain with their local utility, there is no change in their service. Ohio in particular has had significant success with Community Aggregation. The market development period envisioned by Senate Bill 3 (SB 3) has largely been implemented through rulemakings and detailed proceedings before the commission. Aggregation, specifically governmental aggregation, has led the way. In the first two years of electric choice:

- More than 150 local governments passed ballot issues and were certified by the Public Utilities Commission of Ohio to allow local units of government to represent their communities in the competitive electricity market. Ohio is home to the Northeast Ohio Public Energy Council (NOPEC), the largest public aggregator in the United States. NOPEC represents 112 communities in eight counties and more than 350,000 residential customers.

Of those customers who have switched in Ohio, aggregation programs account for:

- Nearly 93% of residential customers who have switched in Ohio.
- More than 88% of commercial customers who have switched in Ohio.
- Nearly 20% of industrial customers who have switched in Ohio.

## **Introduction to AB 117**

In California, AB 117 (Chapter 838, Statutes of 2002) authorizes a single city or county, a city and county, or by a group of cities, cities and counties, or counties acting as a "Community Choice Aggregator" to combine the electrical loads of willing consumers in the community for the purpose of lowering costs and protecting consumers (Public Utilities Code (PUC) Section 366.2(c) (1)).

Essentially a community choice aggregator assumes responsibility for negotiating the purchase of electricity for program participants while the local IOU continues to transmit and deliver that electricity through its existing system. Community choice aggregators "may group retail electricity customers to solicit bids, broker, and contract for electricity and energy services for those customers" (PUC Section 366.2(c) (1)).

Community choice aggregation would allow the City and County of San Francisco to utilize the local IOU's (PG&E) existing transmission and distribution system to deliver electricity to the residents, businesses and municipal facilities.

## **Status of California Public Utilities Commission (CPUC) Process for Community Aggregation**

The authority to develop the specific rules needed to implement community aggregation is vested in the California Public Utilities Commission (CPUC or Commission). These rules will critically determine whether community aggregation is a viable option

for San Francisco and other local governments in California. To date, the CPUC has been slow to establish policies and procedures for the implementation of Community Aggregation. However, because of a peculiarity in the legislation, the Commission was bound to address how a community choice aggregator becomes an administrator of funds generated by the Public Goods Charge (PGC)<sup>1</sup> by July 15, 2003. The CPUC did meet this deadline. The CPUC does not face any other legislatively mandated deadlines for developing global rules for community aggregation.

AB 117 amended PUC Section 381.1 to read “(a) No later than July 15, 2003, the Commission shall establish policies and procedures by which any party, including, but not limited to, a local entity that establishes a community choice aggregation program, may apply to become administrators for cost-effective energy efficiency and conservation programs established pursuant to Section 381.” The CPUC issued Decision #03-07-034 on July 10, 2003. Decision #03-07-034 interprets the sections of the Public Utility Code that allow a Community Choice Aggregator to be an administrator of public goods funds. Decision #03-07-034 also provides guidelines for becoming an administrator (based on the CPUC energy efficiency policy manual as modified by Decision #03-07-034), details information to be provided from IOU’s, and defines energy efficiency program funding for Communities in which the Community Choice Aggregator does not become a public goods funds administrator. Decision #03-07-034 also suggests the CPUC will establish a framework for implementing a Community Choice Aggregation program in the near future.

The broader issues that the CPUC will need to address are contained in Section 4 of this report, under the heading “Regulation – Role of the CPUC in Designing Community Aggregation.” It is expected that these issues will not begin to be addressed by the Commission until late summer or early fall.

Until the CPUC addresses the details contained in their review of the implementation of Community Aggregation, most noticeably the exit fees, it is difficult to quantify the costs and benefits of an overall program.

For the City and County of San Francisco, this presents both a complication and an opportunity. It would be easier for San Francisco if the CPUC established the policies and procedures prior to the City and County’s development of an implementation plan. On the other hand, by developing a preliminary plan for Community Aggregation, the City and County of San Francisco may have more latitude and leverage in terms of fashioning the CPUC’s policies and procedures regarding Community Aggregation.

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<sup>1</sup> The PGC is a charge collected through energy sales that funds primarily investments in energy efficiency and low-income discounts..

## Status of Community Aggregation in California and San Francisco

A number of cities in California have expressed in interest in exploring their options and evaluating the potential benefits and risks of implementing Community Aggregation under AB 117. At least a dozen cities in the state are actively evaluating their options under AB 117 and have hired or are in the final stages of retaining counsel and consulting services to assess the feasibility of community aggregation. CCSF has developed a coalition, Cities for Community Aggregation, which currently has approximately 17 member cities, predominantly in Northern California. Limited outreach has been required to form the coalition. Many local governments will not evaluate whether to proceed with community aggregation until the Commission rules are in place.





Section 2

TECHNICAL AND LEGAL ANALYSIS OF AB 117

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## Section 2

# TECHNICAL AND LEGAL ANALYSIS OF AB 117

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### Electrical Aggregation under AB 117 (Migden) (Chapter 838, Statutes of 2002)

#### Applicability

The consolidated government of the City and County of San Francisco qualifies as a consumer choice aggregator under AB 117. "Community choice aggregator" includes any city, county, or city and county that is not within the jurisdiction of a local publicly-owned electric utility (providing services as of January 1, 2003) and whose governing board decides to aggregate the loads of its residents, businesses and municipal facilities in a "communitywide electricity buyers' program" (PUC Section 331.1).

Currently, Hetch Hetchy Water and Power (HHWP or Hetch Hetchy) is the only publicly-owned utility providing electric services in San Francisco. HHWP is a support bureau of the SFPUC, a unit of the executive branch of the City and County. HHWP provides electricity to all of San Francisco's municipal facilities and sells power to the Turlock Irrigation District (TID) and the Modesto Irrigation District (MID) under long-term contracts. HHWP does not provide electricity to the retail market in San Francisco.

Depending on the load to be aggregated and the organizational structure that the SF LAFCO Board decides, the aggregator may be required to consult with HHWP. AB 117 provides that a community choice aggregator may not aggregate electrical load that is already served by a local publicly-owned electric utility (PUC Section 366.2(c) (1)).

#### Requirements for the Implementation Plan

Before implementing a Community Choice Aggregation program, the aggregator must satisfy a number of requirements under AB 117. The aggregator must create an Implementation Plan "detailing the process and consequences of aggregation" for public review and submission to the CPUC. The Implementation Plan must contain the following information:

- "An organizational structure of the program, its operations, and its funding."
- "Ratesetting and other costs to participants."
- "Provisions for disclosure and due process in setting rates and allocating costs among participants."

- “The methods for entering and terminating agreements with other entities.”
- “The rights and responsibilities of program participants, including, but not limited to, consumer protection procedures, credit issues, and shutoff procedures.”
- “Termination of the program.”
- “A description of the third parties that will be supplying electricity under the program, including, but not limited to, information about financial, technical, and operational capabilities” (PUC Section 366.2(c)(3)).

### Selecting a Governance Structure

If the City pursues Community Aggregation, one of the first decisions that needs to be made is the type of organizational structure that the aggregator will operate under. There are several options available to the City and County of San Francisco for structuring the governance of Community Choice Aggregation. Such options include:

1. operating Community Aggregation within the SFPUC under one of its existing units, such as Hetch Hetchy;
2. vesting governance authority in another existing department of the City and County;
3. creating a new department within the City and County to act as aggregator;
4. contracting with another public agency to provide management services;
5. entering into a Joint Powers Agreement (JPA) with other public agencies; or
6. creating a municipal utility district to serve as aggregator.

### Utilize SFPUC/Hetch Hetchy

The City and County may choose to manage Community Choice Aggregation through the SFPUC and possibly one of its operating units, such as Hetch Hetchy.

#### *Overview*

- **SFPUC:** SFPUC operates under the executive branch of the City and County of San Francisco and is governed by five Commissioners, appointed by the Mayor to four-year terms. SFPUC is presently authorized to contract for the furnishing of heat, light and power for municipal purposes. In addition, SFPUC has “exclusive” responsibility for overseeing the “construction, management, supervision, maintenance, extension, operation, use and control of all water and energy supplies and utilities” for the City and County. SFPUC is comprised of “operational units,” including the General Manager’s Office, Hetch Hetchy Water and Power and the Utilities Engineering Bureau. (San Francisco Charter sections 3.100, 4.112; San Francisco Administrative Code Section 2A.130)
- **Hetch Hetchy:** Hetch Hetchy generates electricity for all of San Francisco’s municipal uses by operating four hydroelectric power plants and hundreds of miles of electrical transmission and distribution lines originating approximately 10 miles from HHP’s Oshaugnessy Dam in Yosemite National Park. This power flows through PG&E’s transmission grid in Hayward for final distribution

to San Francisco accounts. Hetch Hetchy also sells surplus power to Modesto and Turlock Irrigation Districts, other public utilities and some commercial customers. However, Hetch Hetchy does not serve residential consumers. Hetch Hetchy also purchases power as necessary to meet the needs of its customers.

Hetch Hetchy's Resource Management Group ("Resource Management Group") manages Hetch Hetchy's power supply, transmission and distribution contracts, and is responsible for metering, billing, field design consultations, construction management and technical assistance for customers.

- **Utilities Engineering Bureau:** SFPUC's Utilities Engineering Bureau designs, constructs and repairs facilities under Hetch Hetchy's control and oversees power projects in SFPUC's Capital Improvement Program.

#### *Advantages*

- The ability to utilize SFPUC's existing, knowledgeable staff that already has a wide-range of experience in the power industry, including contracting for wholesale power supply scheduling of power, settlement, forecasting of electric loads, and distribution and technical expertise.
- Avoid the expense and delay of creating and staffing a new department within the City and County or a new public agency.
- The SFPUC has been charged with the development of the City and County's Electrical Resource Plan and is the lead agency for implementation of resource development, including solar projects and the acquisition of the LM 6000 generating units acquired as part of the Williams Companies settlement with the State of California.

#### *Disadvantages*

- SFPUC, including Hetch Hetchy, does not currently serve the residential retail market or have experience in that area.
- SFPUC may not have the resources to take on the additional responsibility of serving as community choice aggregator.
- Impact of Prop A approved by the voters in November 2002.

#### **Utilize Other Existing Departments**

The City and County may decide to vest management authority in an existing department other than SFPUC or one of its operational units such as Hetch Hetchy.

#### *Advantages*

- Maintain local control over aggregation.

#### *Disadvantages*

In addition to those disadvantages listed under the SFPUC option, additional disadvantages include:

- Potentially more expensive and time consuming than through SFPUC.

- May overlap or conflict with SFPUC's existing functions and authority.

### **Create New Internal Department:**

The City and County may decide to create a new department within itself to administer the aggregation program.

#### *Advantages*

- Maintain local control over aggregation.

#### *Disadvantages*

In addition to those disadvantages listed under the SFPUC option, additional disadvantages include:

- More expensive and time consuming than through SFPUC or another existing department within the City and County.
- May overlap or conflict with SFPUC's existing functions and authority.

### **Contract with Other Public Entities**

The City and County may elect to contract with another local agency to manage San Francisco's Community Choice Aggregation program. (Government Code Sections 54980 – 54983)

#### *Advantages*

- Very flexible – ability to tailor contract provisions to meet the needs of the City and County.
- Potentially shift entire workload to other parties while City and County retains ultimate control over the program.
- Potentially shield the City and County from liability by shifting liability to other parties.
- Easier to terminate than a JPA or department within the City and County.

#### *Disadvantages*

- Time and expense of implementation and monitoring performance may outweigh benefits.
- City and County must maintain staff to perform these functions.
- There is no existing "outside" public entity with experience in servicing the San Francisco residential customer.
- Other party, representing additional clients, may not be responsive to San Francisco's needs.

### **Enter into Joint Powers Agreement**

Under the Joint Exercise of Powers Act (Government Code Section 6500 et seq.), the City and County may enter into a JPA with one or more public agencies to jointly exercise any power that is common to all parties to the agreement. The agreement

may provide for the creation of a new public agency (a JPA) to exercise this power. (Government Code Sections 6503, 6503.5) AB 117 expressly contemplates such action, stating “community choice aggregator” includes: “Any group of cities, counties, or cities and counties whose governing boards have elected to combine the loads of their programs, through the formation of a joint powers agency established under” the Joint Exercise of Powers Act. (PUC Section 331.1)

#### ***Advantages***

- Ability to leverage regional purchasing power into stronger negotiating position.
- Greater stability through regional commitment, partnering with agencies, such as East Bay Municipal Utility District.
- Potentially provides a regional solution.
- Create separate legal entity (JPA) with independent officers and directors.
- JPA form allows for expansion.

#### ***Disadvantages***

- A regional body concerned with regional issues may not adequately address the unique, local needs of San Francisco.
- Added expense of creating and staffing another government entity.
- City and County must maintain staff to perform these functions.
- Potential for political problems as JPA officials are appointed, not elected.

#### **Create Municipal Utility District**

Under the Municipal Utility District Act (PUC Section 11501 et seq.), the City and County may join with another public agency outside its jurisdiction in creating a municipal utility district to perform the functions of aggregator.

#### ***Advantages***

- Municipal Utility Districts have broad authority to provide power to inhabitants, including the ability to acquire PG&E’s facilities.
- Create separate legal entity with independent officers and directors.
- Voters decide the issue of formation and elect directors to govern the district.

#### ***Disadvantages***

- Expensive to form and operate.
- Lengthy formation process.
- According to the San Diego Regional Energy Office (SDREO): “Community aggregation is Direct Access on a large scale, similar to formation of a municipal utility, except that a municipal utility is self-governing, must purchase power or build plants and transmission lines, assume responsibility for distribution, billing and meter reading. Under aggregation, most of the responsibilities remain with the IOU [investor owned utility]. The aggregator procures electricity on the

wholesale market to be delivered through the IOU's infrastructure." (SDREO Legislative Update Report to the Regional Energy Policy Advisory Council, September 4, 2002)

### **Rate Setting and Other Costs to Participants**

In setting rates, there are certain rules the City would have to follow. For example, rates must be reasonable and nondiscriminatory. In absence of evidence to the contrary, municipal rates are presumed to be valid (*Durant v. City of Beverly Hills* (1940) 39 Cal.App.2d 133). Rates may be subject to Proposition 218, adopted in 1996, adding Articles XIII C and XIII D to the California Constitution. Cities' ratesetting functions may also be subject to charter and/or municipal code restrictions, including bond covenants (*The California Municipal Law Handbook*, p. IV-78 (2002 ed.)).

There are two generally accepted methodologies used in developing rates. The first method, the "cash needs approach," is based on the projected cash needs of the entity. The second method, the "utility approach," involves the calculation of a rate of return on the utilities rate base and includes depreciation as part of the analysis. Most government-owned utilities use the cash-needs approach in determining rates unless they are under the jurisdiction of a state utility commission or regulatory body that requires the use of the utility approach. It is likely that the City and County will use the cash needs approach when developing rates.

In setting rates, policies will need to be adopted regarding the allocation of shared costs and overheads that will need to be recovered through rates.

The aggregator may use as a basis for developing its rates those policies adopted by other special districts and municipal-owned utilities such as the Sacramento Municipal Utility District (SMUD), Los Angeles Department of Water and Power (LADWP), or the City of Anaheim (see **Appendix A**). Most if not all municipal-owned utilities and IOUs publish rate schedules for the various customer classes. Typical classes of customers can include residential, small commercial, large commercial, industrial, street lighting, municipal and economic development. Most utilities provide detailed information regarding charges and rate options, and have developed policies regarding rate setting.

### **Provisions for Disclosure and Due Process in Setting Rates and Allocating Costs among Participants**

The aggregator must ensure that adequate notice is provided during the rate-setting process. In the Implementation Plan, the aggregator should provide specific provisions for notice and due process rights (including bill inserts, public hearings and public notices) during the rate-setting process.

Other municipal utilities have adopted policies and procedures to ensure due process rights, and have taken "practicable" measures to inform all affected customers of any changes in rates.

The allocation of costs among the participants/classes of customers in developing the rates would be done based on the cost to provide to each individual class. This allocation can be done through a cost of service study that assigns costs to the various customer classes. Rates would then be set to recover the cost to provide power for each class of customer. During the normal rate-setting process, customers will have the right to review and comment on these cost-of-service studies.

### **Methods for Entering and Terminating Agreements with Other Entities**

A community aggregator may have contracts with IOUs and other governmental or nongovernmental entities relating to energy purchases or sales. These contracts may consist of informal letter agreements or formal agreements delineating purchase and service responsibilities (The California Municipal Law Handbook, p. IV-76 (2002 ed.)). These contracts will normally be entered into when there is a need to buy or sell power or provide some other type of service to its customers. Termination of these agreements will be addressed in the individual agreements.

Examples of agreements that the aggregator may enter into include power purchases, power sales, purchase/construction/operation of generating unit(s), and fuel. An agreement with the local IOU will also have to be developed for those services provided by the IOU to the aggregator.

### **The Rights and Responsibilities of Program Participants, Including, but not Limited to, Consumer Protection Procedures, Credit Issues, and Shutoff Procedures**

Other municipal-owned utilities have developed and approved rules and regulations that address consumer protection, credit, deposits, billing and shutoff procedures.

For example, publicly-owned utilities, such as SMUD (see **Appendix A**), have established various rules that address application for service, the establishment and reestablishment of credit, deposit requirements, notices to and from customers, disputed bills, discontinuance and restoration of service and customer service fees.

Comprehensive rules and procedures were developed for the IOUs to implement Direct Access. Many of these could be applicable to Community Aggregation, such as Direct Access Service Requests (DASRs) for initiating service changes, payment arrangements, and credit policies. To the extent they are applicable; they will not have to be developed.

The formation of a community aggregator raises certain issues regarding the above mentioned rules. Issues that would have to be addressed include whether a community aggregator customer would have to apply for service with the local IOU provider and also the community aggregator or just the IOU. In the latter case, if application procedures were the same for both the aggregator and IOU, then the community aggregator would reimburse the IOU for the cost to provide that service to the customer. The aggregator could establish an application service charge that recovers the cost of providing the service and have the customer pay it. Under AB 117, a customer is allowed to withdraw from the program without penalty within the first

60 days of enrollment. However, the aggregator will likely desire to develop an exit fee for those customers who leave the program after 60 days. This fee would be similar to a stranded cost charge, since the aggregator will more than likely have entered into long-term agreements to purchase power to meet the customer's projected load.

Other issues that are similar between the aggregator and the IOU include the establishment of credit, deposit requirements, and notices to customers. Policies on these issues probably should be the same for both the aggregator and IOU. Otherwise, there is the opportunity for considerable confusion for a customer who has to comply with two distinct credit and deposit policies.

Issues that will likely require different policies and rules between the aggregator and the IOU include disputed bills, discontinuance and restoration of service, and customer service fees.

### **Disputed Bills**

The disputed bill process may not be able to be the same because the regulating entities of the IOU and community aggregator will be different. The IOU is regulated by the CPUC and the aggregator will more than likely be governed and regulated by a local board or commission.

### **Discontinuance and Restoration of Service**

The circumstances requiring discontinuance of service may be different for the two entities because of the level of risk the aggregator and IOU will be able to accept. Factoring into this risk assessment is each entity's share of the total cost to provide service and how this can change with fluctuating energy markets. The City must be assured that it will be paid by PG&E for the generation service it is providing to its customers who are paying PG&E. The timing of PG&E's payment to the City for generation revenues collected on its behalf is critical, as are the credit/collateral arrangements. The fluctuation of energy prices may not be a critical piece of the payment chain, but will be an issue for customer collection if the customer pays a price for electricity based on the spot price. In that instance, the risk is that the customer will not pay, not that PG&E will not pay. A significant upswing in a wholesale market that flows through to the customer would result in the community aggregator expecting to collect a larger chunk of revenue from PG&E. These changes in value owed can be covered by collateral arrangements with PG&E.

A second risk related to wholesale energy price fluctuations is the counterparty risk between the third-party supplier and the community aggregator. If the third party defaults on its obligations as a result of volatility in the spot market, then the role of PG&E as a provider of last resort is an important consideration, and the city is open to risk in this manner.

A number of consumer protection policies will also need to be developed that address such issues as anti-redlining, anti-slamming, provider of last resort once a customer has opted out, and shut-off for non-payment.

## Customer Service Fees

Customer services fees will more than likely be different because of the separate cost structure for the aggregator and IOU.

## Termination of the Program and Termination by Customers

It is not planned to have an expected date for the termination of the program. As long as the goals and objectives of the program are being met, it is anticipated that the program will operate as an ongoing entity.

If termination of the program becomes an option or necessary, then there will be numerous factors or issues that will have to be resolved such as existing power agreements (buy and sell), generating assets, other assets and other agreements that the aggregator has entered into.

With regard to termination by customers:

- Customers that are community aggregated have advance notice and a 60-day window during which they can opt-out.
- If they return to utility in that period, there is no penalty.
- If they opt-out beyond that window, they would face re-entry fees by statute from PG&E. They could also face city exit fees, if such were imposed.
- If a customer opts out, it is not clear that they can at a later date choose Community Aggregation.

## A Description of the Third Parties that will be Supplying Electricity under the Program, Including, but not Limited to, Information about Financial, Technical, and Operational Capabilities

It is anticipated that the aggregator will procure power from third parties. These outside providers will need to meet certain qualifications in order to be eligible to enter into contracts with the aggregator. Financial strength, credit risk, and experience are some of the factors that will be part of the decision in determining whether the entities qualify as a power supplier. The supplier will also be required to meet certain technical and operational requirements as established by both the aggregator and PG&E.

## Statement of Intent

The Implementation Plan must also contain a statement of intent from the community choice aggregator. The aggregation program must provide for “universal access,” “reliability,” “equitable treatment of all classes of customers” and all other requirements under state law or by the commission concerning aggregated service. (PUC Section 366.2(c) (4))

Universal access must be defined. This will be particularly important if a phase-in of customer classes or service areas within San Francisco is anticipated.

The Implementation Plan and any subsequent changes must be adopted by the Board of Supervisors at a noticed public hearing. (PUC Section 366.2(c) (3)) If adopted, the plan, and any other requested information, must be filed with the CPUC for a determination of the "cost-recovery mechanism" that will be imposed on the community choice aggregator and paid by its customers "to prevent a shifting of costs to an electrical corporation's bundled customers." (PUC Section 366.2(c) (5); Legislative Counsel's Digest) The community choice aggregator may not provide electricity to consumers until CPUC makes its determination. (PUC Section 366.2(c) (8))

### Requirements of the Ordinance

The City and County must also adopt an ordinance to implement the program. (PUC Section 366.2(c) (10)) The text of the ordinance should be discussed in the Implementation Plan. At a minimum, the ordinance should discuss each of the following:

- The Agency's authority to implement a Community Choice Aggregation program;
- Efforts to comply with the requirements of AB 117 and all applicable rules and regulations; and
- Public participation.

### Steps after the Implementation Plan are Filed

1. Within 10 days after the Implementation Plan is filed, CPUC will notify PG&E. (PUC Section 366.2(c)(6)) Existing electrical corporations are required to cooperate with community choice aggregators attempting to investigate, pursue or implement Community Choice Aggregation programs. Electrical corporations must provide billing and load data that explains, for instance, electrical needs and usage. CPUC will adopt procedures to guide this process and will determine what information is to be provided. (PUC Section 366.2(c)(9))
2. The City and County must offer the opportunity to purchase electricity to all residential customers within San Francisco. (PUC Section 366.2(b)) It will need to be determined whether phase-in is allowable and, if so, over what time frame.
3. Following adoption, the City and County must fully inform all customers of their right to opt out of the Community Choice Aggregation program and to continue to receive service as a bundled service customer from the existing electrical corporation. All customers must be notified twice within two months or 60 days prior to the date of automatic enrollment. In addition, notification must continue for participating customers for at least two consecutive billing cycles after enrollment. Notification may be given, for instance, in the form of bill inserts or direct mailings. All customers, except for those who declare otherwise, must be served by the program. (PUC Section 366.2(c)(2), (11), (13))

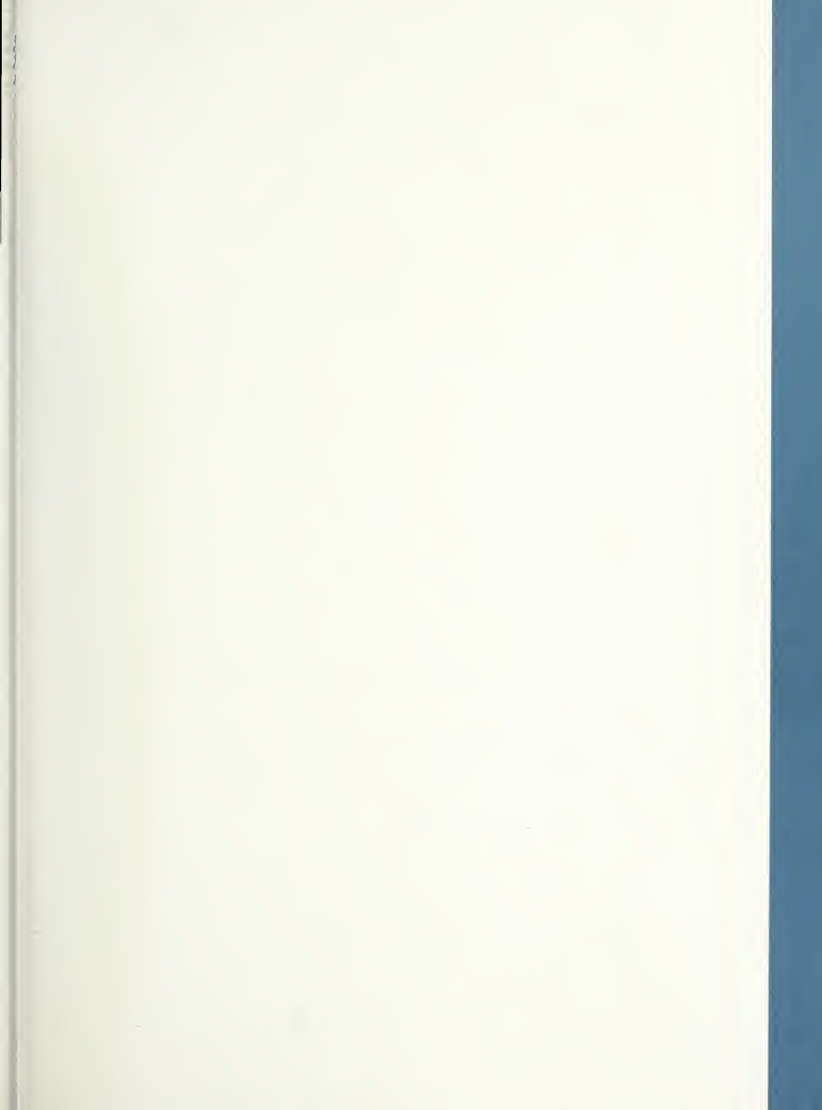
4. Notification must contain the following information:

- Customers will be automatically enrolled.
- Each customer has the right to opt out of the program without penalty.
- The terms and conditions of community choice aggregated service. (PUC Section 366.2(13)(A))

In addition, notification must provide customers with a straightforward means to opt out of the program such as a self-addressed return postcard. (PUC Section 366.2(c) (13) (C))

5. The community choice aggregator may ask the CPUC to approve the notice that will be given and to order the existing electrical corporation to provide such notification to customers at the public entity's expense. The existing corporation must cooperate with the aggregator in assessing the feasibility and cost of providing notice through the corporation's billing process. (PUC Section 366.2(c)(13)(B))
6. When its contract is signed, the community choice aggregator must notify the electrical corporation that community choice service will begin within 30 days. (PUC Section 366.2(c)(15))
7. CPUC must adopt rules for implementing Community Choice Aggregation before any program may begin. (PUC Section 366.2(i)(3))
8. By July 15, 2003, CPUC will adopt policies and procedures for a community choice aggregator to apply to become an administrator for cost-effective energy efficiency and conservation programs for which its customers are eligible.
9. As a community choice aggregator, the City and County of San Francisco must register with CPUC. The CPUC may require the City and County of San Francisco to provide additional information in order to verify compliance with rules for consumer protection and other procedures. (PUC Section 366.2(c)(14)) At the time of registration, a community choice aggregator is required to post a bond or provide evidence of sufficient insurance to cover any reentry fees that may be imposed against it by CPUC for involuntarily returning a customer to the service of an electrical corporation. (PUC Section 394.25(e))
10. Subject to determination by CPUC, a community choice aggregator must pay the electrical corporation all costs that are "reasonably attributable" to the aggregator, including costs associated with "business and information system changes." (PUC Section 366.2 (c) (17)).







## Section 3

# BENEFITS AND RISKS OF COMMUNITY AGGREGATION IN SAN FRANCISCO

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## Section 3

# BENEFITS AND RISKS OF COMMUNITY AGGREGATION IN SAN FRANCISCO

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## Introduction

There are many factors that will influence the decision for San Francisco to implement Community Aggregation and for constituents to participate. Some of these are economic. Others are related to quality of life and local control. The following discussion addresses those factors that are seen as benefits or pros of Community Aggregation and those factors that can be characterized as risks, cons, or hurdles to implementation.

## Benefits (Pros)

### Local Control of Wholesale Power Supply Portfolio

San Francisco residents have opposed the continued operation of the Hunter's Point and Potrero power plants for some time for environmental reasons. They have been frustrated in their attempts because the plants are deemed necessary by the California Independent System Operator (CAISO) to retain reliability in San Francisco. Were the City to have a dependable revenue stream from Community Aggregation services, it could invest in power supply solutions, including the support of green resources that could facilitate the closure of these facilities. A combination of the Williams Companies combustion turbines, cogeneration, distributed generation, and transmission upgrades will go a long way towards creating energy independence for San Francisco and for obtaining permission from the CAISO to shut down these older power plants.

### San Francisco Load Profile Relative to PG&E

Because of the coastal influence on weather in San Francisco, the electricity load profile differs markedly from that in other parts of California, where air conditioning loads contribute to much higher summer peaks. During peak periods, whether summer or winter, electricity prices are generally higher than during off-peak periods. During very hot weather, prices may be several times higher than on normal days. It would, therefore, be expected that it would be less expensive, on average, to serve the San Francisco load.



### Analysis

R. W. Beck conducted four separate studies to determine the economic benefits associated with differences between San Francisco's load shape and PG&E's load shape. The following assumptions and data were used to develop the four scenarios:

- Hourly load profiles for PG&E were taken from FERC Form 714 and San Francisco's hourly load profile was provided by the City of San Francisco.
- Load duration curves were based on the hourly load profiles. For presentation purposes, PG&E's hourly load data was adjusted by a common multiplier to match PG&E's peak with San Francisco's peak.
- 2002 NP-15 ex-post prices were downloaded from the CAISO website and used as part of the second scenario. These prices include the effects of congestion but not ancillary services.
- For purposes of the third scenario, baseload is defined as the amount of minimum capacity required to serve load for 85% of the hours in a year. Intermediate load is that required to serve the additional load between 15% and 85% of the hours. Peak load is that required in excess of base and intermediate for 15% of the hours or less. Each hour was assigned its share of base, intermediate, and peaking load.
- Resource costs for base, intermediate and peak load resources were based on current costs of construction, development, and operation of these three types of resources. Assumptions were made about heat rates, capacity factors, debt, and O&M to arrive at an average cost of each resource. Gas prices of \$4 per MMBtu and \$6 per MMBtu were used in the analysis for purposes of sensitivity.
- In the last analysis, hourly load data for San Francisco and PG&E is mapped against 1999 PX Constrained Market Clearing Prices for NP 15. The prices were downloaded from the University of California Energy Institute.

The first scenario was based on applying projected monthly average peak and off-peak prices for 2005 to the PG&E system and San Francisco hourly loads for 2002. This method showed no benefit as a result of the San Francisco load shape.

The second scenario applies actual hourly CAISO ex-post prices to the two hourly load shapes. This method also showed no benefit to the San Francisco load shape but suffered from erratic CAISO ex-post prices.

The third scenario took annual load duration curves for the two service areas based on 2002 data and fit baseload, intermediate load, and peaking resources to the different load duration curves. Costs of base, intermediate, and peaking resources were developed using current costs of construction, development, and operation of three types of resources. A gas price of \$4 per MMBtu was assumed and a sensitivity case for gas at \$6 per MMBtu was run.

Figures 3-1 and 3-2 illustrate this scenario. Figure 3-3 shows the difference between San Francisco's load duration curve and PG&E's load duration curve. The PG&E curve shows a greater proportional need for peaking and a proportionally lesser need for intermediate generation.

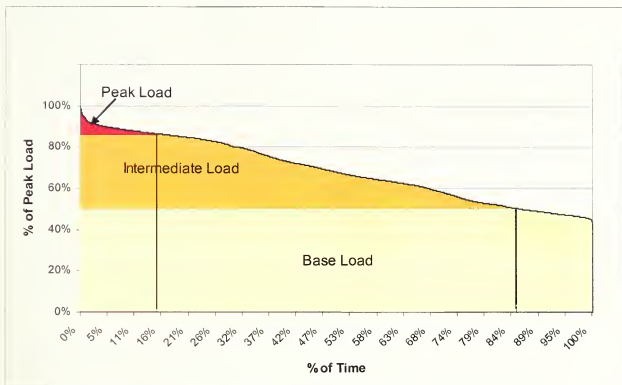


Figure 3-1: San Francisco Annual Load Duration Curve

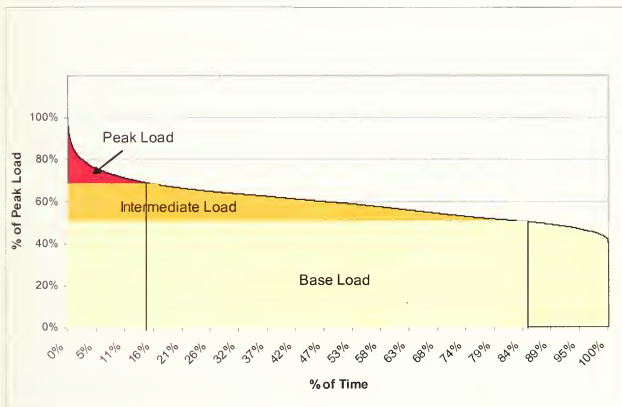
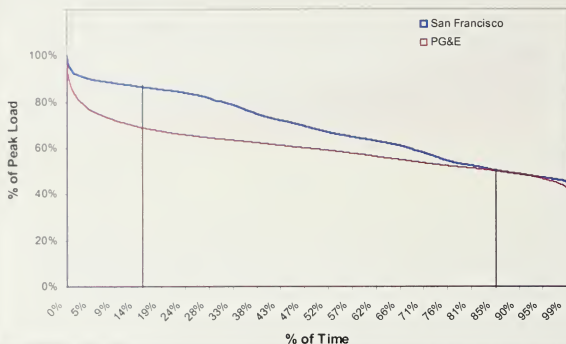


Figure 3-2: PG&E Annual Load Duration Curve



**Figure 3-3: San Francisco vs. PG&E Annual Load Duration Curve**

Because PG&E has a mix of coastal, Central Valley, and mountain service areas, it has a high annual load factor and better load diversity than most utilities. It, therefore, has a relatively small percentage of peaking requirements and a large percentage of baseload. San Francisco has even smaller peaking requirements but a larger percentage of intermediate load that is somewhat more expensive than baseload. These two offset, resulting in a very small cost advantage for the San Francisco load. Based on this summary analysis, very little, if any, advantage of superior load characteristics vis-à-vis PG&E is likely to accrue to San Francisco with Community Aggregation.

The last scenario applies to hourly California Power Exchange (PX) prices from 1999 to both San Francisco and PG&E 1999 hourly loads. Because the electric market structure was relatively stable in 1999, hourly California PX market clearing prices were less erratic than the 2002 CAISO ex-post prices used in Scenario 2. However, while hourly 1999 California PX prices were less erratic and had reasonable diurnal and seasonal patterns, the analysis still showed little economic benefit to San Francisco's load shape relative to PG&E's load shape. San Francisco's estimated annual average price is \$31.84 per MWh and PG&E's estimated annual average price is \$32.16 per MWh. The small difference in average annual prices suggests there will be little economic benefit solely due to differences between San Francisco's load shape and PG&E's load shape.

## **Conclusions**

R. W. Beck estimated the economic benefits that would accrue to San Francisco based on differences between the City's load shape and PG&E's system load shape. R. W. Beck completed four different scenarios to evaluate the benefits of San Francisco's load shape relative to PG&E's system shape. All four led to the same conclusion that there is relatively little economic benefit to San Francisco's load shape. Whether the analysis was done on hourly loads and prices or using a simulated portfolio of generation resources (baseload, intermediate, and peak), the results were similar. San Francisco is not likely to see large savings in energy costs solely due to its system load shape. However, there may be customer-specific or class level savings that result from a study of customer or customer class-specific load shapes.

In all four cases, the lack of availability of good data and the loss of an effective electricity market in 2000 reduced the reliability of the analyses. For future analyses, current load information by area and customer sector should be requested from PG&E in order to increase the level of confidence in the analyses.

## **Opportunity for Greener Power Portfolio**

Residents of San Francisco have shown their support for renewable resources by approving Proposition B on November 6, 2001, to finance solar photovoltaic generation in San Francisco. Additionally, the city is exploring other renewable options, including biomass and wind. There are several ways that the objective of a greener power portfolio can be met within Community Aggregation. They include:

1. San Francisco could collect and manage the allocations and expenditures of Public Benefits Funds. With the Community Aggregator allocating funds to program categories, it could provide funding to applicable programs based on local needs or desires. IOUs in California are required to spend these funds in the area prescribed by California legislation. There is no local flexibility to determine which categories are employed. The California Energy Commission (CEC) is responsible for managing this portion of PG&E's public benefit revenue and the Legislature has dictated funding amounts for each category. Since state law requires PG&E to spend approximately \$30 million annually on RD&D, the San Francisco share would be nearly \$2.1 million that could be allocated to renewable resources, energy efficiency, or low-income customer assistance.
2. Customers can be offered more tariff choices that allow them to select green power or other options.
3. San Francisco can pursue wind power generation that is at least partially firmed by its Hetch Hetchy hydroelectric generation.
4. San Francisco can pursue waste to energy at appropriate landfill sites.
5. The SFPUC operates the clean water system and can evaluate cogeneration to use methane produced in the process.

### Protection from Wholesale Energy Price Volatility

There are trade-offs between linking rates to wholesale prices and attempting to unlink rates from short-term price changes. Time-of-use rates often include on-peak/off-peak price differentials that reflect long-term average cost differences. These encourage customers to use lower cost energy off-peak and to modify their energy use habits. Some very large customers are willing to accept real-time wholesale market price links and are willing to curtail operations when hourly prices exceed some preset limit. These approaches promote economic efficiency and optimize use of generation assets. Unfortunately, a large percentage of customers prefer price stability and want to reliably budget for their electricity costs. San Francisco can balance the competing objectives of economic efficiency and the desire for price stability in the following ways:

1. Offer choices to customers that will, on average, produce the lowest cost but include price linkage, whether time-of-use or real-time.
2. Offer rates that are not linked to market price changes and that include a premium for the costs of managing the inherent risk for the City.
3. Develop a power supply portfolio where a substantial portion is owned or contracted for in a manner that fixes costs.
4. Use Hetch Hetchy, to the extent possible given constraints caused by water supply needs, contract obligations, and The Raker Act, during periods of high market prices to reduce San Francisco's exposure to such prices.
5. Balance the hedging of fuel supply so that the percentage that is hedged at least covers the load for customers on fixed rates.
6. Establish a rate stabilization fund that builds up when market prices are lower than those forecast and is drawn down when prices are high.
7. Develop Energy Adjustment Charges. These charges can be based on 6- or 12-month moving averages of at-risk market prices or fuel prices and smooth out the effects of real-time price volatility.

Using these strategies in a comprehensive pricing plan, gives customers choices that match their financial and business objectives, manage San Francisco's risks of matching costs and revenues, and still support economic efficiency.

### Opportunity to Provide Real-Time Pricing for Peak Shaving – Direct Control over City's Resource Requirements

The City has priority use of Hetch Hetchy power and has had little economic incentive to manage electricity use at the larger energy-using facilities. The cost of power to the City is not currently influenced by market prices. Assuming that The Raker Act, contract obligations and water delivery obligations allowed the following changes, City loads could be managed to shave peak loads and optimize the use of Hetch Hetchy and potentially to support cogeneration at selected locations.

1. Establish rates for municipal loads that reflect a melded value, including the cost of hydroelectric production and its value in the market.
2. Enhance the controls, such as adding Automated Generator Controls (AGC), and operating protocols at Hetch Hetchy to increase the value of its production. This would increase on-peak generation and reduce off-peak generation while still meeting all of the water delivery requirements.
3. Evaluate cogeneration opportunities at the airport, wastewater treatment facilities, or other city facilities.

The expansion of loads through Community Aggregation that are eligible for Hetch Hetchy power will provide significant economic incentive to more effectively schedule and use this resource. However, in implementing change, the City may have to wrestle with the shifting of some Hetch Hetchy benefits from municipal loads to the larger set of Community Aggregation customers.

## **Ability to Control and Direct Public Benefit Dollars**

It is estimated that PG&E collects in excess of \$12 million annually from San Francisco customers for Public Benefit Programs. The requirements are set by the California Legislature and funds are administered by the CPUC and the CEC. The Public Benefit revenues are allocated to the following four types of expenditures established by the Legislature:

1. Energy efficiency and demand-side management
2. Renewable resources
3. RD&D
4. Low-income assistance

Under local control, San Francisco would have a similar funding requirement for Public Benefit programs (as a percent of revenues), as does PG&E. However, they would be able to determine the extent to which each category is funded and can select and administer the individual programs. They can assure that expenditures are kept in San Francisco to best serve San Francisco constituents. They can also direct funds towards programs that satisfy local objectives, such as green resources and energy efficiency. If contractors are used to implement Public Benefit programs, San Francisco will be able to apply their own purchasing and contracting standards.

## **Opportunity for City to Develop Renewable Resource Base that can be Sold to San Francisco Customers**

In addition to the benefits discussed under “Greener Power Portfolio” and “Control of Public Benefit Dollars,” San Francisco could set up a separate Green Portfolio that customers could elect to participate in. Some utilities offer blocks of green energy at a 1¢ to 2¢ premium. Some offer the opportunity for customers to make a contribution on their bill payment that is dedicated to the construction of new renewable resources. Finally, arrangements similar to that now in place with the Moscone Center could be replicated. The bottom line is that under Community Aggregation, San Francisco and

its customers could form partnerships to encourage and develop renewable resources beyond that which is likely to happen under status quo.

### **Provide Retail Market Access for Hetch Hetchy Hydro**

Hetch Hetchy production is currently scheduled around the clock because the priority load in the City's municipal load that is very flat. That is, it is relatively constant on an hourly and daily basis. The cost of producing this power is about \$17 per MWh. The average annual wholesale market value of that energy is approximately \$30 per MWh assuming \$4 per MMBtu natural gas. However, the market price changes hour by hour and can vary from 0 to at least \$150 per MWh. The Raker Act requires that Hetch Hetchy power be used for San Francisco loads and loads of its customers and that surpluses be sold to TID and MID. The irrigation district contracts have been or are in the process of being renegotiated and may terminate. That will free up more power for San Francisco customers. Under Community Aggregation, Hetch Hetchy power could be scheduled (within water delivery protocols) to optimize the economic value of generation. If market prices are high, generation would be maximized. When prices are low, only the minimum level required would be scheduled and market purchases substituted. This could easily *increase* the value of Hetch Hetchy generation by 200% or more given typical market prices.

### **Provide Retail Access for Combustion Turbine Power Plants**

The SFPUC is preparing to install four combustion turbines under a contract with the CDWR. During the first 10 years, CDWR will have first call on the generation (SFPUC could acquire the resource after five years if it were to exercise opt-out provisions in the contract). If it is useful to San Francisco, the SFPUC could schedule operations when not required by CDWR. After 10 years, San Francisco will have full ownership and control of the units. Since CDWR is paying the capital costs, any generation costs for San Francisco will be for variable operation and maintenance and fuel. Without Community Aggregation, San Francisco would not have a place for this power most of the time, except to firm Hetch Hetchy power. In the first 10 years, if San Francisco got use of the combustion turbines only 5% of the time (based on a combination of the incremental cost being "in the market" and not being scheduled by CDWR, the value for San Francisco customers could be over \$400,000 per year. After 10 years, the value would increase to over \$1.3 million annually.

### **Opt Out Provides a Relatively Secure Rate Base**

One of the most important features of AB 117 is that once Community Aggregation is implemented, customers automatically transfer to the Community Aggregator as the supplier of their energy, unless they opt out. They continue to have that energy delivered over the incumbent utility's wires (in this case, PG&E). If they are concerned that their costs will go up under Community Aggregation (or for any other reason), they can opt out and continue to purchase their energy from PG&E. This requires an active decision. Since a Community Aggregator is not likely to proceed to implementation if customers will not benefit economically, and assuming an effective

public outreach program, it is unlikely that more than 10% of customers will choose to opt out. As a result, San Francisco would start with a large customer and load base over which to spread start-up and operating costs. This will also help in obtaining competitive pricing for large blocks of power and for contracting for any services that are out-sourced.

## **Effect on San Francisco Financial Strength**

Assuming that San Francisco retains 90% of the load for Community Aggregation, annual revenues from power sales should approximate \$225 million annually. Retention of 5% to 8% of these revenues would not be out of line with practices in publicly-owned utilities. Some of this could go to infrastructure and some to other municipal purposes. The addition of \$11 to \$18 million in annual revenue base should provide benefits to the overall financial strength of San Francisco. Over time, as the financial community gains confidence in long-term results, this could affect financial ratings and the cost of debt.

## **Achieve some of the Objectives of Municipalization without a Long-Term Struggle with PG&E or the Requirement of a Ballot Initiative**

One of the key hurdles to municipalization is the opposition from the incumbent utility and their ability to sway voters with costly campaigns that cannot be matched by a public agency. If PG&E views Community Aggregation as a non-threatening alternative to full municipalization, they are less likely to mount an aggressive campaign against it. The failure rate of municipalization attempts is high and the costs and time involved in elections, almost certain litigation, exercise of eminent domain, valuation of facilities, and severance costs are daunting. The costs of implementing Community Aggregation are expected to be only a fraction of the cost of full municipalization (excluding the cost of facility acquisition and business infrastructure development). At the same time, 60 to 70% of total electric utility revenues come from the power supply component that could transfer to the Community Aggregator. Additionally, the greatest impact on total electricity costs will be related to the power supply element. Effective management, power supply planning, and risk management can influence costs substantially. Therefore, the greatest opportunity for consumer savings is attached to this part of the business.

## **Risks (Cons)**

### **Exit Fees and Related Uncertainties**

AB 117 includes protection for existing customers such that the CPUC is to establish a cost recovery mechanism to avoid shifting any of the following costs:

- CDWR electricity purchase costs.

- Electricity purchase contract obligations at September 24, 2002, that are recoverable from PG&E customers under regulated rates.
- Debt service related to CDWR bonds for electricity.
- Other unavoidable CDWR costs.
- PG&E costs related to:
  - Past under collections allowed to be recovered in regulated rates.
  - Additional unrecovered net unavoidable purchase contract costs.

The best indicator of the level of these costs is the exit fees for continuing Direct Access customers. Although still under review, the exit fee is currently 2.7¢ per kWh. It is not yet clear when a final number will be established for the Direct Access customers or for Community Aggregation. Because of timing differences and potential inconsistencies in the definition of what costs should be included, the exit fees for Direct Access customers may differ from the cost recovery for Community Aggregation. The uncertainty is compounded over time since PG&E is over-recovering under current tariffs and surcharges to such an extent that unrecovered costs should be paid down relatively quickly. The outcome of the PG&E bankruptcy workout may also affect the Community Aggregation obligation.

Until the obligation is known, it will be difficult to definitively determine the economic benefits for Community Aggregation customers.

### **Near-Term Opportunities to Use Hetch Hetchy Resources are Limited**

San Francisco has contract obligations with TID and MID to sell Hetch Hetchy surpluses. The contract with MID has been renegotiated and will terminate December 31, 2007. TID contract negotiations are in progress and the outcome unknown. Other constraints on the use of this resource include hydrologic conditions, water supply deliveries and contracts, Raker Act covenants, and municipal load growth. In any event, it is unlikely that power from Hetch Hetchy in excess of that used for municipal loads will be available before 2008 to serve Community Aggregation loads.

The result of the unavailability of substantial low-cost power from Hetch Hetchy is that San Francisco will initially have to rely on third-party suppliers for most of the supply for Community Aggregation. This will most likely be a mix of short and intermediate forward purchase contracts at market prices. Further evaluation will be required with different gas and electricity market prices and different assumptions regarding PG&E melded power supply costs, including bankruptcy decisions, cost of contracts with Qualifying Facilities, and CDWR costs.

## **Minimizing Portfolio Risks Will Add to San Francisco Procurement Costs**

To the extent that San Francisco offers fixed rates to a sizeable percentage of the Community Aggregation load, but is dependent on a portfolio that includes market exposure to gas or electricity prices, it is likely to want to hedge against high market prices. Hedges can take the form of contracts with caps/ceilings, forward purchases, options, etc. Each type of hedge carries some premium. In some cases, San Francisco would have to put up a credit line or surety for at least 20% of market exposure. In others, they could purchase an option at costs between \$3 and \$5 per MWh. The total cost of risk management will depend on the portfolio mix, owned resources, ability to use Hetch Hetchy when market prices are high, the availability and cost of credit, and the availability of financial reserves such as rate stabilization funds. For purposes of planning, it could be assumed that power supply risk management will add approximately 5% to the melded cost of power (over direct costs).

It should be noted that PG&E will have similar objectives, but that a larger percentage of their portfolio (represented by their hydro, nuclear, Qualifying Facility, and CDWR contracts) will be at risk to market prices. Most PG&E risk will be to gas prices, which they are in a strong position to hedge because of their ownership of gas transmission and storage. PG&E's cost of power supply risk management is likely to be only 1% to 2% of their melded cost of power.

## **Remaining Risks**

Even with effective power supply risk management, there will be business risks. These include loss of load beyond that planned for, counter party risks for hedging contracts, system failures, regulatory, and legislative change. The largest perceived regulatory risk is that of additions to or true-ups in exit fees.

## **Infrastructure and/or Contracting Requirements**

San Francisco already has systems in place for customer service (meter reading, billing, call center) for water and wastewater operations. They also have some power procurement, scheduling, operations, and settlements infrastructure to support Hetch Hetchy Water and Power. However, the scope of all these activities will undergo considerable change with a large Community Aggregation program. It is likely that the entire customer service function will need to be upgraded, including a new Customer Information System and an enhanced Call Center capability. The power supply functions will need risk management, trading, and scheduling enhancements.

These upgrades will include capital costs for systems and hardware as well as additional staffing. It will take time to acquire the personnel and systems needed to implement such a plan. At least in the short term, some of these functions can be contracted out. The Implementation Plan will need to include evaluation of existing infrastructure, interim decisions on contracting vs. in-house services, and definitive estimates of costs and staffing requirements.

### Regulatory Issues

Regulatory issues include those noted earlier, such as exit fees to be established by the CPUC and some federal issues, such as FERC's proposal for Locational Marginal Pricing (LMP). Transmission into San Francisco is limited and occasionally congested. Generation within San Francisco is also limited and there is an initiative to shut down much of that generation for environmental reasons. The result is a long-term potential for high dependence on transmission. Upgrades to transmission are planned and in the permitting process. However, even if completed, San Francisco may be subject to transmission congestion and the costs of LMP.

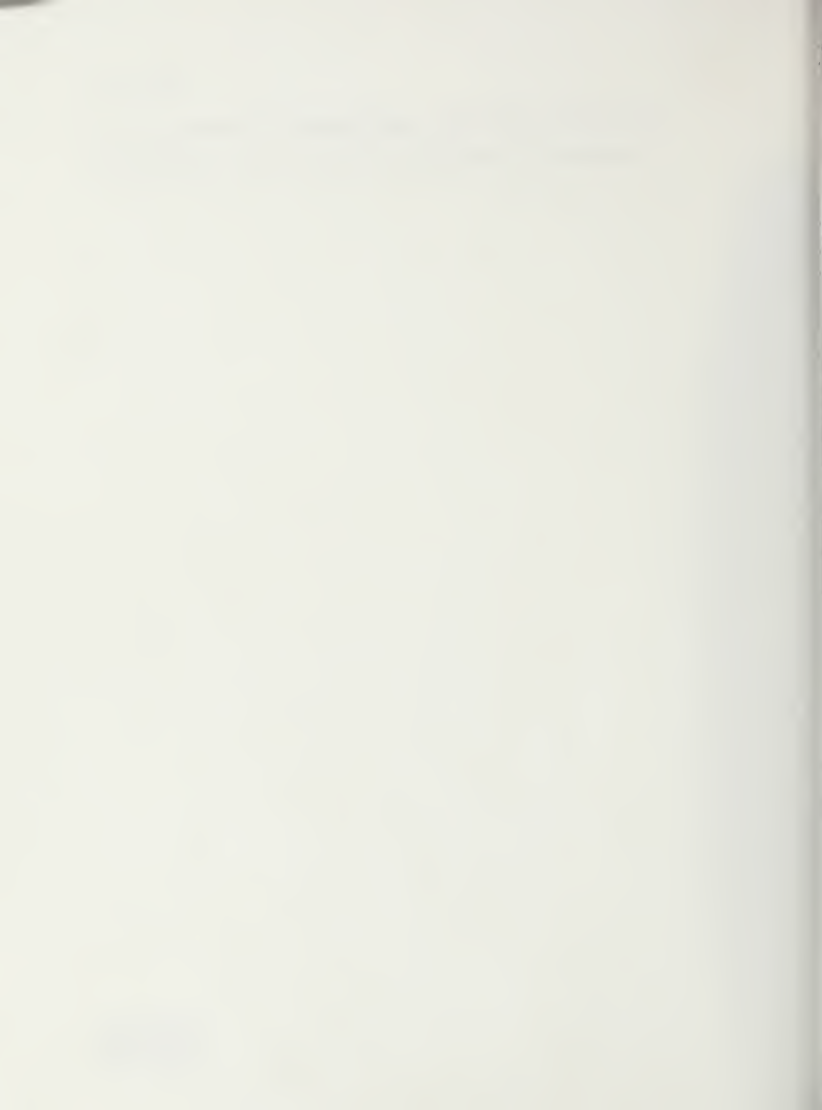
The Community Aggregation Implementation Plan will need to evaluate potential LMP costs based on the most recent transmission plans for the entire Bay Area, the CAISO protocols for acquiring firm transmission rights, the projected costs of such rights, the expectations for local generation, and the status of FERC's regulations that would impose LMP.





**FACTORS THAT WILL DETERMINE FEASIBILITY OF  
COMMUNITY AGGREGATION IN SAN FRANCISCO**

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## Section 4

# FACTORS THAT WILL DETERMINE FEASIBILITY OF COMMUNITY AGGREGATION IN SAN FRANCISCO

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## Regulation – Role of the CPUC in Designing Community Aggregation

A community choice aggregator preparing to provide electric service to community customers is required by PUC Section 366.2 to develop an Implementation Plan. The contents of the Implementation Plan are also specified by Section 366.2 and include:

- An organizational structure of the program, its operations, and its funding.
- Ratesetting and other costs to participants.
- Provisions for disclosure and due process in setting rates and allocating costs among participants.
- The methods for entering and terminating agreements with other entities.
- The rights and responsibilities of program participants, including, but not limited to, consumer protection procedures, credit issues, and shutoff procedures.
- Termination of the program.
- A description of the third parties that will be supplying electricity under the program, including, but not limited to, information about financial, technical, and operational capabilities.

The primary purpose of the plan is for the community choice aggregator to articulate the details of electric service it will provide to community customers. The plan must be approved by the governing Board of the community choice aggregator and then filed with the CPUC. The Legislature's primary intent on requiring the plan to be filed with the CPUC is to ensure there is no cost shifting between the customers participating in Community Choice Aggregation and those that remain with the incumbent IOU. The CPUC has the authority to:

- Review the Implementation Plans of community choice aggregators.
- Determine the size and type of non-bypassable charges and to which customers they will apply.
- Collect any and all information deemed necessary by the CPUC in order for the Commission to make a binding decision on the issues.
- Create rules for Community Choice Aggregation plans.

- Require community choice aggregators to register with the CPUC before considering the Implementation Plan.
- Set rules and rates for costs imposed on IOUs by community choice aggregators.
- Set standards for consumer protection.

The goal of the CPUC filing is to establish the appropriate level of exit fees and to approve the Implementation Plan of the community choice aggregator. The CPUC process for setting exit fees and approval of Implementation Plans will likely follow the regulatory pattern established by similar rulemakings. The CPUC will likely require the following steps before a decision on the issues is made:

- **Application Filed by Community Choice Aggregator.** The application will delineate and support how the community choice aggregator's Implementation Plan meets the statutory requirements for such a plan and why it would be in the public interest for the plan to be adopted. A proposal on the appropriate level of exit fees would also likely be required.
- **Discovery and Intervenor.** Intervenor and interested third parties will intervene in the case and elicit information from the community choice aggregator through the discovery process. The community choice aggregator may also ask questions of the intervenors to the case. Intervenor may include IOUs; the CPUC staff; the Office of Ratepayer Advocate (ORA); The Utility Reform Network (TURN); interested consumer, industrial, or commercial groups; other cities or government entities; and other agencies, including CAISO.
- **Intervenor File Direct Cases.** Intervenor will analyze the application filed by the community choice aggregator and either support or criticize the application in intervenor's own filings before the CPUC.
- **Settlement Discussions.** Settlement discussions will involve attempting to reconcile differences between the application of the community choice aggregator and the comments on the application put forth by intervenor.
- **Hearings.** Absent a settlement agreement, the application details will be litigated before the CPUC. Expert testimony on the details of the application would be required. Intervenor would have competing experts that would either support or critique the application.
- **CPUC Decision.** After hearings and review of the evidence presented to the CPUC, Commissioners will make a decision based on the merits of the case. The process of getting to a final decision often involves competing proposed decisions written by separate Commissioners or by an Administrative Law Judge. Comments by intervenor and the applicant are also considered.
- **Implementation/Appeal.** After the final decision by the CPUC has been issued, the community choice aggregator or any of the intervenor to the case can appeal the decision at the CPUC. If the CPUC upholds its original decision, the decision can be appealed to the state or federal court systems. If all parties are satisfied with the original decision, then the community choice aggregator will implement the

terms of the decision, which may involve changing pricing, terms of service, billing systems, or resource plans.

The entire process can often take six months or more to complete. If an appeal is made to the courts, far more time can be required. The case of a community choice aggregator will involve significant operational and financial issues, including rate-making, resource planning, electric reliability, scheduling, balancing, transmission issues, billing and settlement, legal analysis, risk management, organizational and administrative structure, forecasting, and exit fee determination. Given the potential scope of issues, a Community Choice Aggregation plan would likely take longer than a standard CPUC rulemaking docket dealing with a single issue.

The CPUC is currently working through a number of issues that could influence policy for implementation of Community Choice Aggregation. In addition, the California Legislature also has number of bills pending that will, if passed, have an impact on Community Choice Aggregation service. These issues are summarized below.

### **Utility Resource Planning (R.01-10-024, D.02-10-062)**

The CPUC is in the process of ramping-up resource planning and development functions of the existing California IOUs. The CPUC's goals are to have the IOUs present plans that detail how the IOU will meet load and energy obligations in both the short and long run. As PG&E prepares to meet its long-term load requirements, new plans may be built or new long-term contracts signed. Because PUC Section 366.2 gives the CPUC the authority to assign exit fees based on stranded utility assets, the long-term resource planning taking place currently at the CPUC could affect the size and type of exit fees ultimately paid by customers of a community choice aggregator.

### **CDWR Power Purchase Costs (D.02-11-022, D.02-12-052, R.02-01-01)**

Under AB1x, signed during the height of the California energy crisis, the CDWR was given the authority to purchase power for the three California IOUs. The CDWR purchased both short- and long-term power. The long-term contracts signed by the CDWR have been assigned to the California IOUs (D.02-12-052) for administration and dispatching and are a main component of the CPUC's Direct Access Cost Responsibility Surcharge (DA CRS) (D.02-11-022). The DA CRS is the current non-bypassable charge that applies to Direct Access customers (those who started Direct Access before the CPUC suspended Direct Access). Because PUC Section 366.2 requires the CDWR long-term contract costs to be paid by Direct Access customers, the DA CRS will also most likely apply to Community Aggregation customers. A new DA CRS will be determined by the CPUC in July 2003 and will likely take into account contract renegotiations that have occurred during the last year.

## **CDWR Bond Costs (D.02-10-063, D.02-11-074)**

The DA CRS also pays for the bonds that have been issued by the State of California to pay for the short-term power costs incurred by the CDWR in purchasing short-term energy for California's IOUs during the energy crisis. Because PUC Section 366.2 requires the CDWR bond costs to be paid by Community Aggregation customers, CDWR bond costs will also be included in the exit fee paid by Community Aggregation customers.

## **PG&E Bankruptcy (Petition #01-30923)**

On June 13, 2002 a settlement agreement was signed between the CPUC and PG&E. The settlement agreement keeps all of PG&E's various operations under CPUC regulatory control, pays all creditors claims, slightly lowers rates immediately, and seeks to re-establish PG&E's credit ratings to investment grade. The settlement agreement is subject to ratification by both the bankruptcy court and the CPUC. The CPUC is holding public participation hearings that will extend to the end of August 2003 and will be issuing a decision on the settlement agreement most likely in September or October 2003. The bankruptcy court plans to have creditors vote on the settlement agreement in August and September 2003 with confirmation hearings in October 2003.

## **PG&E 2003 General Rate Case (A.02-11-017)**

The PG&E General Rate Case (GRC) allows the CPUC to evaluate all of PG&E's costs, rates, and energy forecasts. As a result of this proceeding, PG&E's rates will likely need to rise, but because of the rate freeze, rates will not adjust immediately. However, after resolution of PG&E's bankruptcy and the end of the rate freeze, PG&E's rates should adjust to reflect the increases authorized in the 2003 GRC and the effects of removing the energy surcharges added to PG&E's rates during the energy crisis. Any adjustments or changes to PG&E's short-run or long-run rate structure will have an effect on the competitiveness of a Community Choice Aggregation program.

## **Direct Access Credit Determination (A.98-07-003)**

PG&E and Southern California Edison (SCE) are currently involved in a proceeding at the CPUC to determine the long-term credit that will be paid to customers on Direct Access. Because Community Choice Aggregation is very similar to Direct Access, the long-term credit for Direct Access will also likely be the long-term credit for Community Choice Aggregation. PG&E's current Direct Access credit methodology is that Direct Access customers receive a bill based on bundled rate components and then a credit to reflect the difference between non-bypassable costs and PG&E's weighted average cost of energy. PG&E is proposing to change that methodology to a bottoms-up approach. PG&E will charge Direct Access customers for all unbundled rate components (distribution, transmission, public purpose charges, non-bypassable

fees, etc.) except the generation component, which is equal to PG&E's weighted average cost of energy (hydro, nuclear, CDWR contracts, QFs, other short- or long-term purchases). The CPUC issued a proposed decision in this case on April 3, 2003, that supports PG&E's new methodology. If the proposed decision is approved by the Commissioners, the new methodology could be in place by September 1, 2003.

### **Renewable Portfolio Standard (SB 1078)**

Senate Bill 1078 (SB 1078) was signed by Governor Davis on September 12, 2002. The bill requires 20% of all electric energy resources to be from renewable sources by 2017. Community choice aggregators are also required to meet the standard.

### **Return of Direct Access (AB 428) (Pending)**

AB 428 would create an electricity market structure that is similar to the existing natural gas market structure in California. The bill would disaggregate utility customers into three groups: core, non-core, and core-elect. Core customers would be any customer under 500 kW, non-core would be any customer over 500 kW, and core-elect customers would be non-core customers who choose to purchase their energy from the existing IOU. The bill eliminates a utility's obligation to serve for non-core customers on January 1, 2006, unless the non-core customer becomes a core-elect customer for at least three years. The bill requires the CPUC to establish short-, medium-, and long-term resource plans by July 1, 2004. AB 428 also allows the CPUC to lower the threshold for non-core from 500 kW to a new level possibly as low as 200 kW on or before January 1, 2009. Non-core customers choosing Direct Access would be responsible for non-bypassable charges as defined by PUC Sections 366.1 and 366.2. Through the return of Direct Access, the establishment of rules for participating in core, non-core, and core-elect service, and the development of long-term resource plans for core customers, this bill could have a significant impact on Community Choice Aggregation programs. This bill is currently in the Senate Energy, Utilities, and Communications Committee, where it has been granted reconsideration after failing to pass on July 8, 2003.

### **New Municipalities, Non-Bypassable Charges, and Direct Access (AB 816) (Pending)**

AB 816 makes municipalities responsible for non-bypassable charges as determined by the CPUC when annexing customers from the service territory of an adjacent IOU. Existing customers who are exempt from exit fees will continue to be exempt. The bill would also reinstate Direct Access for customers over 500 kW when:

- The Cost Responsibility Surcharge has been adopted.
- Revenue bonds to pay for CDWR short-term purchases have been issued.
- IOUs are operating under long-term resource plans.

- Direct Access issues in CPUC R.02-01-011 are resolved.
- Rules for costs imposed by customers switching from utility to Energy Service Provider service and back again are resolved.

Large customers or businesses with multiple sites may aggregate their load from the various sites to meet the 500-kW threshold.

This bill has been extensively amended since its introduction in the California Assembly and it is presently in committee in the California Senate. Old language that exempted existing IOU customers who are annexed by an existing utility from paying exit fees has been removed. However, the bill would still bring back Direct Access for customers >500 kW. Reinstating Direct Access for large customers limits the availability of Community Choice Aggregation and may increase the costs as large customers with good load shapes would not likely participate in the Community Choice Aggregation program.

### **Re-Regulation of Electricity (SB 888) (Pending)**

This bill has a very far-reaching scope that essentially returns existing California IOUs to vertically integrated companies with the obligation to serve all loads within their respective service territories. This bill has also been extensively altered since passing the California Senate and the bill now preserves the Direct Access and Community Choice Aggregation provisions of existing law. The bill failed passage in a California Assembly Committee on July 11, 2003, but was granted reconsideration.

### **Short- and Long-Term Resources Available for Community Aggregated Load**

The City and County of San Francisco owns, operates, and has contracted for significant power resources as part of its operation of Hetch Hetchy, and more recently, its participation in the development of green power and gas-fired generation. This section outlines the resources available to the City and identifies potential issues that could influence their availability or use for purposes of Community Aggregation.

### **Short-Term Resource Position**

Electrical generation output from Hetch Hetchy facilities are obligated under existing provisions and contracts to serve San Francisco municipal load, the irrigation districts (TID and MID), and Norris and San Francisco International Airports. The irrigation districts have certain first rights of refusal to excess power. Beyond that, HHWP has banking arrangements with PG&E. The agreements and contracts create a complicated interrelated set of issues that might make it difficult to serve loads beyond those currently served in the short run. Nonetheless, such options, including adjusted use or enhancement of facilities (ALC), could enhance short-term options for Hetch Hetchy.

Currently, Hetch Hetchy provides enough output to meet all City load and District obligations in the months of February through June. In July through January, other resources or contracts are needed to meet current demand.

In order to firm HHWP power deliveries, HHWP signed a Power Purchase Agreement with Calpine during the energy crisis of 2000-2001. HHWP recently renegotiated that agreement with Calpine to better match contract supply with required power deliveries and to lower the cost of Calpine resources. The contract runs through July 2006.

The SFPUC has initiated the development of other projects, such as the 670-kW Moscone Solar Project that will produce power for the City in the short term. In addition, other projects, such as Norcal, energy efficiency, and retrofit projects and distributed generation projects, will likely evolve in the short term.

## **Long-Term Resource Position**

For purposes of this draft of the report, economic analysis of power supply does not include any assumed new or adjusted resources. In other words, the power supply component is status quo. This is the most conservative assumption that can be made at this time.

The Hetch Hetchy contract with Modesto has been modified to terminate Class 3 service in December 2004. From January 2005 through December 2007, Modesto has the right of first refusal to power from Hetch Hetchy. Beginning January 1, 2008, all output will be available to San Francisco. Negotiations with TID are underway which could yield similar results if successful.

In the long term, the Williams Companies turbines will be available to San Francisco; however, due to commitments to the CDWR, it is not available for City use until the City is able to take ownership of the units.

Other long-term resources include solar and renewable projects under development, as well as any contracts that may be entered into by the City.

It is important to note that there remain substantial issues that would need to be resolved in order to implement Community Aggregation should the City desire to use its own resources to meet its load. For example, transmission access would need to be arranged. This could occur either through a renegotiation of the existing Interconnection Agreement with PG&E or, more likely, additional separate transmission agreements with PG&E and others to transport power to the City. From the perspective of the City and County of San Francisco, it would be better to address transmission for Community Choice Aggregation separately from existing transmission service contracts. In addition, risk management strategies would need to be employed regardless of the source of supply.







**PRELIMINARY ASSESSMENT OF FEASIBILITY OF  
COMMUNITY AGGREGATION IN SAN FRANCISCO**

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## Section 5

# PRELIMINARY ASSESSMENT OF FEASIBILITY OF COMMUNITY AGGREGATION IN SAN FRANCISCO

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Initial data comparison performed by R. W. Beck indicates that the load characteristics of the City and County of San Francisco are similar to those of PG&E. This analysis cannot be confirmed until PG&E makes site-specific San Francisco data available to the City, as required by PUC Section 366.2.

## Resource-Based Comparison

R. W. Beck has completed a preliminary analysis of the potential savings that San Francisco may enjoy as a result of implementing Community Choice Aggregation. The analysis compares the amount of credit PG&E is likely to give as a result of Community Aggregation against the cost of new energy resources that would need to be procured to meet load in San Francisco. Numerous assumptions were needed as part of this analysis due to uncertainty caused by ongoing energy related regulatory and legislative processes and by lack of detailed information about energy load, customers, and resources available to San Francisco. Should San Francisco proceed with Community Aggregation, PG&E would be required to provide detailed information about energy use and customers (as required by PUC Section 366.2). With this detailed data, the following analysis could be refined to reflect actual San Francisco customer data. In order to draw some general conclusions, the following assumptions were key to developing the analysis of savings generated by Community Choice Aggregation.

- The PG&E credit used in the analysis is assumed to be equal to PG&E's current direct access credit. PG&E bills direct access customers for bundled utility service (generation, distribution, transmission, etc.) and then credits them for the generation component. The credit reflects the weighted average cost of PG&E's internal generation resources (hydroelectric, nuclear, QF, short term, and DWR contracts) netted against the non-bypassable charges assigned to direct access customers by the CPUC. PG&E's credits are shown in Schedule E-EC of PG&E's tariff. The methodology for applying this credit is likely to change in the near future as the CPUC issued a Proposed Decision on April 3, 2003 in A.98-07-003 that allows PG&E to go to a new direct access billing methodology. However, for the purpose of this study the current methodology was assumed to apply.
- Credits escalate each year based on changes in the weighted average cost of PG&E's resource mix. PG&E's resource mix is assumed to include: hydroelectric (15%), nuclear (22%), QFs (26%), CDWR contracts (28%), and short-term purchases (9%). Hydro and nuclear energy costs are assumed to

increase at the rate of inflation while DWR contract costs and QF prices are averaged and held constant. Both PG&E's resource mix and the average cost of PG&E resources come from PG&E's 2003 GRC. Credits are further adjusted in 2012 to reflect both the termination of DWR contracts and the elimination of most of the Cost Responsibility Surcharge implemented by the CPUC to pay for the DWR contracts.

- Sales figures period were calculated from the "Electricity Resource Plan - Choosing San Francisco's Energy Future" prepared collaboratively by the SFPUC and San Francisco Department of Environment in December 2002.
- Because San Francisco's resource planning efforts are currently ongoing and the City's formulation of a resource plan that could reliably meet the energy needs of customers participating in Community Choice Aggregation within San Francisco is just beginning, the analysis of savings assumes that all of the City's energy needs are met through energy purchases from short term markets. The cost of those resources comes from the CEC market price forecast in the "2002 - 2012 Electricity Outlook Report" issued November 2001.
- San Francisco will no doubt have other energy resources available to it when, and if, the city chooses to participate in Community Choice Aggregation. Electric resources such as the solar power generated from San Francisco's solar initiative, power generated by the four Williams Companies combustion turbines recently provided to San Francisco by the State, Hetch Hetchy resources, or the impact of the Renewable Portfolio Standard (SB 1078) were not considered as part of the analysis. However, these resources will certainly have a positive impact on the cost, reliability and potential savings generated by a Community Choice Aggregation plan.
- CAISO fees and transportation costs were estimated at 8% of the market price and scheduling and administration costs were estimated at 3% of the market price.

Given these assumptions, Table 5-1 details the results of the preliminary analysis.

**PRELIMINARY ASSESSMENT OF FEASIBILITY OF COMMUNITY  
AGGREGATION IN SAN FRANCISCO**

**Table 5-1  
Estimated Savings (Cost) of Community Aggregation**

Year	Total Load Including Losses (MWh)	Average Credit (\$/MWh)	Savings from PG&E Credit	San Francisco Resource Costs	Total Annual Savings
2004	6,057,119	\$37.32	\$215,009,117	\$201,702,064	\$13,307,053
2005	6,221,823	\$37.72	\$223,171,624	\$186,468,045	\$36,703,579
2006	6,297,841	\$38.48	\$230,501,861	\$195,736,888	\$34,764,973
2007	6,373,858	\$39.27	\$238,050,185	\$205,174,490	\$32,875,694
2008	6,449,875	\$40.16	\$246,375,311	\$221,940,213	\$24,435,098
2009	6,525,893	\$40.99	\$254,386,441	\$231,799,711	\$22,586,730
2010	6,601,910	\$41.87	\$262,918,750	\$245,492,028	\$17,426,721
2011	6,677,927	\$42.74	\$271,417,681	\$255,731,233	\$15,686,447
2012	6,753,945	\$45.41	\$291,708,013	\$277,384,515	\$14,323,498
2013	6,830,828	\$46.25	\$300,473,293	\$288,124,306	\$12,348,987
2014	6,908,585	\$47.10	\$309,451,123	\$298,980,641	\$10,470,482
2015	6,987,228	\$47.97	\$318,740,550	\$310,246,035	\$8,494,515
2016	7,066,767	\$48.86	\$328,353,014	\$321,935,902	\$6,417,111
2017	7,147,210	\$49.77	\$338,300,377	\$334,066,236	\$4,234,141
2018	7,228,570	\$50.71	\$348,594,948	\$346,653,633	\$1,941,315
2019	7,310,855	\$51.67	\$359,249,496	\$359,715,314	\$(465,818)
2020	7,394,078	\$52.65	\$370,277,266	\$373,269,151	\$(2,991,885)
2021	7,478,247	\$53.67	\$381,692,000	\$387,333,688	\$(5,641,688)
2022	7,563,375	\$54.71	\$393,507,954	\$401,928,168	\$(8,420,214)

As can be seen from Table 5-1, in most years the savings as a result of Community Aggregation is positive. However, the savings are heavily influenced by market prices, as all of San Francisco's load was assumed to be purchased in short-term markets. Therefore resource costs are driven by the forecast of short term energy prices. The savings are determined by the PG&E credit. The credit, while being influenced by market prices, is made up of other PG&E resources (hydroelectric, nuclear, QF, DWR). These resources are assumed to remain under cost of service control during the study period and therefore do not exhibit the same volatility that short term energy markets tend to experience. Therefore, the savings tend to rise when the market price of energy falls and begin to fall as the market price of energy begins to rise. Furthermore, if PG&E is successful in moving their hydroelectric and nuclear resources to their unregulated companies, the savings to San Francisco could be substantially higher than projected in this analysis. Likewise, if San Francisco can effectively integrate low-cost resources, such as Hetch Hetchy and the four new combustion turbines into their resource mix over time, these savings would increase. As more details are provided about how San Francisco will plan to meet the energy requirements of Community Choice Aggregation loads and with what resources, a

better picture of the true savings or costs associated with Community Choice Aggregation will emerge. The assumptions contained in Table 5-1 are a conservative estimate of future cost for both PG&E and San Francisco.

### Risk Assessment

Given the opt-out provision of AB 117, the fact that power markets have returned, at least in the short term, to more normal levels, and that San Francisco may be able to utilize resources, such as Hetch Hetchy power and the Williams Companies combustion turbines as future power supply resources, it would appear that the downside risk of implementing Community Aggregation in San Francisco is low. The one remaining unknown in terms of the analysis is the level of non-bypassable charges that will be established by the CPUC. It will not be known until these charges are established what their impact will be. However, based on previous decisions with regard to Direct Access and discussions of CPUC commissioners on open dockets, R. W. Beck believes that the estimates used in this analysis are indicative of what the CPUC will ultimately adopt.

### Recommended Organizational Structure for Community Aggregation

R. W. Beck's analysis of the advantages and disadvantages of the various potential governance structures identified in Section 2 cause us to recommend that the SFPUC is the most logical choice to lead the development and refinement of the Community Aggregation Plan. The SFPUC is the best choice for taking the lead in terms of further development of the plan, since:

- The SFPUC has “exclusive” responsibility for overseeing the “construction, management, supervision, maintenance, extension, operation, use and control of all water and energy supplies and utilities” for the City and County of San Francisco.
- The SFPUC is the City and County of San Francisco lead agency for resource development, including the acquisition of the four Williams Companies LM6000 generating units and the Moscone solar project.
- The SFPUC has existing resources (Hetch Hetchy) that could possibly be used to provide power supply beyond what is currently delivered to municipal loads.
- The SFPUC is familiar with and has been actively involved in energy-related matters of interest to the City and County of San Francisco, including the closure of the Hunter's Point and Portrero Power Plants, the development of new and improved transmission access into the Peninsula.
- Staff and resources within the SFPUC are better equipped than alternative options to implement Community Aggregation, should LAFCO determine that it is worth pursuing.

## PRELIMINARY ASSESSMENT OF FEASIBILITY OF COMMUNITY AGGREGATION IN SAN FRANCISCO

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Should the SFPUC be selected to lead the further development of the Community Aggregation Implementation Plan, there are several questions that would still need to be resolved, including:

- Further review of the SFPUC bond covenants, the City and County of San Francisco Charter, the San Francisco Administrative Code, and The Raker Act of 1913 (H.R. 7207) in order to ensure that the SFPUC is not hampered in developing, implementing, or funding the plan.
- Certain activities, particularly customer-related services, will likely need to be contracted out either to PG&E or alternative providers at least at the outset of implementation. The SFPUC would need to be able to enter into agreements for the provision of these services.
- Impact of Proposition A approved by the voters in November 2002







## CONCLUSIONS AND RECOMMENDED NEXT STEPS

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## Section 6

# CONCLUSIONS AND RECOMMENDED NEXT STEPS

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## Conclusions

Based on R. W. Beck's analysis of the options and opportunities presented to the City and County of San Francisco by AB 117, it is our conclusion that Community Choice Aggregation under AB 117 holds significant benefits for the San Francisco community. These benefits include:

- Local control over power resources.
  - Could enable the closure of Hunter's Point and Portrero Power Plants consistent with the City's objectives.
  - Establishes potential future market for City resources, including:
    - Williams Companies LM6000 combustion turbines
    - Potential Hetch Hetchy output from ongoing contract negotiations
    - Moscone solar resources
    - Other local green or renewable projects
    - Local distributed generation projects
- Greater influence over local transmission access and pricing issues.
- Greater influence over system planning and improvement of electric system reliability problems.
- More control over local public benefit program decisions.

It is also R. W. Beck's conclusion, based on conservative assumptions, that the City and County of San Francisco can achieve significant annual savings by providing for its own resource supply to retail customers. These initial savings estimates could be substantially higher if San Francisco is able to use its low-cost hydro or gas-fired generation to meet customer requirements.

There are a number of factors that will undoubtedly change a final analysis of Community Aggregation, including the determination of non-bypassable charges by the CPUC; site-specific San Francisco load data that PG&E will be required to provide; the outcome of the PG&E bankruptcy; and the ground rules for future pricing decisions either through a market or regulated return basis.

In any case, it appears that the potential benefits of Community Aggregation warrants LAFCO recommending to the City and County consideration of the development and filing of an Implementation Plan with the CPUC.

## Recommended Next Steps

The following outline provides a list of the next steps necessary to pursue implementation of AB 117. These tasks are broken down into the steps needed before and after the Implementation Plan is filed.

### Community Aggregation Next Steps

#### Before the Implementation Plan is Filed

- The City and County of San Francisco determines if Community Aggregation Plan should be filed with the CPUC.
- The City and County of San Francisco determines the organizational structure that the aggregator will operate under (select lead agency).
- The City and County of San Francisco directs the lead agency to create the Aggregation Plan, including:
  - Operation and funding the program
  - Ratesetting
  - Provisions for disclosure and due process for allocating costs and setting rates
  - Methods for entering or terminating agreements with other entities
  - Consumer rights and responsibilities
  - Program termination
  - Third-party descriptions
  - Statement of Intent (universal access, reliability, equitable treatment of all classes of customers)
- City and County of San Francisco Ordinance, including:
  - Agency's authority to implement the Community Aggregation Program Plan
  - Compliance with AB 117 rules and regulations
  - Opportunity for public participation

#### After the Implementation Plan is Filed

- Aggregator is to notify PG&E of the plan filing.
- Customers must be notified twice within two months or 60 days prior to the date of automatic enrollment.
- Customer notification must provide a straightforward means for the customer to opt-out of the program.
- Aggregator must notice PG&E that Community Aggregation will begin within 30 days.

- CPUC may adopt rules before the program may begin.
- Community Aggregator must register with the CPUC and will be required to post bond and provide evidence of insurance.
- Subject to CPUC determination, the Community Aggregator must pay PG&E costs that “reasonably attributable” to the aggregator, including costs associated with “business and information system changes.”

These steps are simply a summary of the process. It is anticipated that it will take approximately four to six months to complete the plan and another four to six months to complete once the plan is filed. Therefore, it is unlikely that Community Aggregation could be implemented much before 2005.









